STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

Proceeding on Motion of the Commission Assessing Implementation of and Compliance with the Requirements and Targets of the Climate Leadership and Community Protection Act	)))))	Case 22-M-0149

JOINT UTILITIES' SUPPLEMENT TO PROPOSAL FOR AN ANNUAL GREENHOUSE GAS EMISSIONS INVENTORY REPORT

I. Introduction and Background

On May 12, 2022, the New York State Public Service Commission (Commission) issued an Order on Implementation of the Climate Leadership and Community Protection Act (CLCPA).[1] The Order directed the Joint Utilities of New York[2] to work with Department of Public Service Staff (DPS Staff) to develop a proposal for an annual Greenhouse Gas (GHG) Emissions Inventory Report and file a draft version for public comment by December 1, 2022. As directed, the Joint Utilities worked with DPS Staff and filed a draft version of the proposal on December 1, 2022.[3] The Proposal provided for annual reporting of emissions associated with natural gas distribution systems in the following three categories:

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[1] Case 22-M-0149, *Proceeding on Motion of the Commission Assessing Implementation of and Compliance with the Requirements and Targets of the Climate Leadership and Community Protection Act*, Order on Implementation of the Climate Leadership and Community Protection Act (issued May 12, 2022) (Order).
[2] Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., Rochester Gas and Electric Corporation, The Brooklyn Union Gas Company d/b/a National Grid NY, KeySpan Gas East Corporation d/b/a National Grid, National Fuel Gas Distribution Corporation, Liberty Utilities (St. Lawrence Gas) Corp., and Corning Natural Gas Corporation (Joint Utilities).
[3] Case 22-M-0149, Joint Utilities' Proposal for an Annual Greenhouse Gas Emissions Inventory Report (filed December 1, 2022) (Proposal).

- Upstream emissions, resulting from the import of natural gas into New York State;
- Attributable emissions, including direct gas system emissions, as well as emissions from utility customer meters; and
- Avoided emissions, where specific activities of a utility may cause measurable emissions reductions.

Based on discussions with DPS Staff in early 2023, the Joint Utilities are filing this supplement to the Proposal to (1) recommend including emissions from end-user combustion as a fourth broad category of emissions, and (2) provide additional information for stakeholder reference. The following sections provide supplemental information on upstream emissions and natural gas system emissions, and then provide a proposed approach to estimate emissions from end-user combustion. The Joint Utilities also include three appendices in support of the statements and positions set forth below.

II. Upstream Emissions

As noted in the Proposal, the Joint Utilities are proposing to use basin-specific emission factors to calculate upstream emissions. The National Energy Technology Laboratory (NETL), a world-class research institution, has published, and continues to update, an extensive analysis of the GHG emissions associated with the parts of the natural gas value chain associated with different production basins in the United States. This approach provides a specific and accurate method to estimate upstream emissions associated with each of the utilities' individual purchases. Conversely, while also based on the emission factors published by the NETL, the New York State Department of Environmental Conservation's (DEC) method for a statewide inventory, as set forth in 6 NYCRR Part 496, is calculated by applying a New York State production-weighted factor to the broader national average emissions factors.[4] The DEC's method does not reflect the more region-specific purchases that are common to New York State utility purchasing practices.

The value of this region-specific analysis is reinforced by a paper published by NETL researchers in late October 2022, entitled *Life Cycle GHG Perspectives on U.S. Natural Gas Delivery Pathways*.[5] The Joint Utilities were unaware of the NETL paper when they filed the Proposal. The NETL paper indicates that 88% of the gas consumed in the northeast U.S. is produced in the Appalachian Basin, a fact that underscores the logic of using a more basin-specific emissions factor for reporting upstream emissions by the Joint Utilities, as described with specific examples in the Proposal.

The Proposal also provided for a "deduction" from the NETL emissions factors to reflect the fact that the NETL factors account for distribution system losses (emissions). Therefore, the deduction from the NETL factors is necessary to arrive at upstream emissions factors that do not double count distribution system losses. Based on discussions with NETL researchers, the Proposal set forth a ten percent deduction in calculated emissions to account for distribution losses. The calculations that describe this ten percent deduction are included in Appendix A. The reasonableness of assigning a ten percent deduction to the NETL basin-specific emissions factors to account for the distribution system component of emissions is supported by the most recent publication of the U.S. Environmental Protection Agency (EPA), *Inventory of U.S. Greenhouse Gas Emissions and Sinks Greenhouse Gas Inventory* (GHGI),[6] further described in

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[4] *See Preliminary Interim Draft Emission Factors for Use by State Agencies and Project Proponents*, NYSDEC Version 02/2021. Available at https://www.dec.ny.gov/docs/administration_pdf/ghgappxclcpaemissfctrs22.pdf.
[5] Available at https://pubs.acs.org/doi/10.1021/acs.est.2c01205?ref=pdf.
[6] Available at https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2021.

the introductory text of the Proposal. EPA's most recent GHGI report indicates that nine percent of natural gas value chain losses can be ascribed to the distribution sector.[7] This independently derived estimate provides further support for the Joint Utilities' recommendation to apply the ten percent distribution factor deduction as a reasonable approximation to all calculations of upstream emissions.

III. Attributable Emissions

As outlined in the Proposal, the Joint Utilities recommend estimating direct distribution system emissions using the Natural Gas Sustainability Initiative (NGSI) Protocol[8] developed by the American Gas Association and the Edison Electric Institute. This method duplicates EPA's GHGI, but provides for more granular entity-level reporting, whereas GHGI is an annual report developed by the EPA that tracks GHG emissions and sinks by source, economic sector, and greenhouse gas type. The NGSI Protocol is already utilized by natural gas companies throughout the United States. As explained in the Proposal, NGSI/GHGI is more comprehensive and reflective of updated emissions factors than the approach used by DEC.[9] A comparison of the emissions factors and sources in NGSI/GHGI versus the GHG Reporting Program (GHGRP) and DEC approach is provided in Appendix B.

In conversations with the Joint Utilities after the Proposal was filed, DPS Staff questioned whether it would be appropriate to include other emissions (referred to herein as "non-gas system emissions") such as those from fleet vehicles, building energy (natural gas, steam, oil) usage, and purchased electricity. While it is not clear to the Joint Utilities that non-

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[7] *Id*.
[8] Available at: https://www.aga.org/research-policy/natural-gas-esg-sustainability/natural-gas-sustainability-initiative-ngsi/.
[9] Case 22-M-0149, Proposal, pp 4-7.

gas system emissions are within the scope of the Order, the Joint Utilities nevertheless contend that these emissions are *de minimis* relative to upstream, direct, and end-user combustion emissions. Furthermore, the quantification of estimated non-gas system emissions can be burdensome (particularly given their relative magnitude compared to other emissions), and may have to rely on data from third parties. Therefore, the Joint Utilities recommend not including non-gas system emissions in the annual GHG Emissions Inventory Report.

To illustrate that non-gas system emissions are *de minimis*, the Joint Utilities provide sample GHG annual emissions data in Appendix C that show non-gas system emissions as a percentage of total GHG emissions for a subset of utilities. Using the Joint Utilities' proposed methodology, non-gas system emissions are approximately 0.1% or less of total annual emissions, as shown in Appendix C.[10]

IV. End-User Combustion Emissions

After consultation with DPS Staff, the Joint Utilities are amending the Proposal to include emissions from end-user combustion in the annual GHG Emissions Inventory Report. The Joint Utilities propose to furnish this information to the Commission so that stakeholders may better understand emissions in New York State. However, the Joint Utilities point out that although they deliver the gas used by their customers, many gas delivery customers purchase their gas from a third-party gas provider. As a result, a significant portion of the gas commodity the Joint Utilities deliver is sourced and sold to customers by other entities.[11] The Joint Utilities propose to use the methodology for end-user combustion emissions established by the EPA in

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[10] Even using other methodologies to estimate GHG emissions, non-gas system emissions do not exceed approximately 1% of total emissions for any company.

[11] Although the Joint Utilities are amending the Proposal to report emissions from end-user combustion from the gas they deliver, they should not be responsible (in the context of emissions limits or allowance obligations) for emissions from gas they do not own, sell or combust.

the GHGI. This methodology was adopted by DEC and the New York State Energy Research and Development Authority (NYSERDA) in the statewide inventory and includes CO_2, CH_4, and N_2O emissions.

Calendar year end-use volumes will be obtained from each utility's annual report to the Energy Information Agency (EIA)[12] and will be categorized in the same manner. Specifically, the end use volumes will be divided into two categories: gas *owned* by the utility and gas *not owned* by the utility. Each of these categories will then be further subdivided into residential, commercial, industrial, electric power,[13] vehicle fuel, and "other" end use subcategories.[14] Using the heat content reported to EIA,[15] the corresponding volumes will be converted to units of energy to which the emission factors shown in Table 1 can be applied.

Table 1. CO_2, CH_4, and N_2O Emission Factors, Natural Gas Combustion[16]

GHG Species	End Use Category	Emission Factor	Unit of Measure
CO_2	All	14.43	mt C/QBtu
CH_4	Residential/Commercial	5	g CH_4/GJ
	Industrial	1	g CH_4/GJ
N_2O	Res/Com/Ind	0.1	g N_2O/GJ
	Electric[17]	0.3	g N_2O/GJ

Note that the emissions factor for CO_2 is in terms of carbon content per unit of energy. As in the EPA and DEC methodologies, a CO_2 to C molecular weight ratio of 44 to 12 is used. With

[12] Annual Report of Natural and Supplemental Gas Supply & Disposition, Form EIA-176.
[13] The Joint Utilities note that combustion emissions associated with electric power generation may also be counted in other venues under the purview of the Commission.
[14] EIA Form 176, Part 6, Items 10.0 and 11.0.
[15] EIA Form 176, Part 6, Item 9.0.
[16] US EPA, Inventory of Greenhouse Gas Emissions and Sinks: Annex 2, Table A-19 (CO_2) and Annex 3-A, Table A-65 (CH_4 and N_2O). *See also*: NYSERDA, Energy Sector Greenhouse Gas Emissions under the New York State Climate Act: 1990-2020: Table B-1 (CO_2) and Table B-2 (CH_4 and N_2O).
[17] Value shown is from NYSERDA Table B-2. Note: N_2O EFs in EPA methodology depend on technology type and range from 0.3 to 1.3 g N_2O/GJ.

respect to CH_4 emissions, the industrial emissions factor is applied to the vehicle[18] and "other" end use categories described above. Lastly, industrial emissions associated with non-energy fuel use of natural gas (*i.e.*, natural gas used as a feedstock) are not accounted for separately. Pursuant to NYSERDA estimates, non-energy use of natural gas in New York is minimal (*i.e.*, approximately 1.3%[19] of all industrial use), so no material impact on total emissions is expected.

V. Conclusion

As explained above, emissions from end-user combustion should be included in the annual GHG Emissions Inventory Report, while non-gas system emissions are *de minimis* and should not be included. The Joint Utilities will continue to collaborate with DPS Staff and look forward to working with other stakeholders in this proceeding.

VI. Appendices

A – Accounting for Distribution Losses in Upstream Emissions

B – Methodology Comparison Table

C – Natural Gas LDC Company Sample Annual Portfolio Emissions

Dated: May 31, 2023

[18] CH_4 and N_2O emission factors for CNG vehicles depend on vehicle type (e.g., light duty, heavy duty) and vehicle miles travelled (VMT). Since this information is not available to the LDCs, the Joint Utilities assume the industrial emission factors for stationary combustion to be reasonable estimates.
[19] NYSERDA Table F-1.

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Appendix A: Accounting for Distribution Losses in Upstream Emissions

Further discussion of the rationale for distribution system deduction from National Energy Technology Laboratory (NETL) total value chain emissions:

This Appendix A provides more detail around the conclusion that it is appropriate to deduct 10 percent of the life-cycle emissions calculated by NETL to account for distribution losses. The discussion of this deduction in the Proposal was supported by footnote number 15; this Appendix A provides additional detailed calculations.

The calculation for the distribution portion of the overall natural gas value chain considers carbon dioxide and methane emissions published by the NETL and includes production, gathering/boosting, processing, transmission storage, storage, transmission pipelines and distribution emissions.

On the attached table, the first two values (production, gathering/boosting) come from Table F-1 of the 2019 NETL report, and are based on an Appalachian Shale basin value. The remainder of the components is the same for all basins and comes from Table 31 of the 2019 report. In all instances, the mean value was used as a simplifying assumption.

The value of 24.023 g CO2e/MJ in the attached table differs slightly from the value shown in footnote 15 (24.1) because the NETL calculation includes negligible amounts of NO2. Inasmuch as NO2 emissions are at least two orders of magnitude smaller than the carbon dioxide and methane emissions, the NO2 emissions are not included in the attached table as a simplifying assumption.

These values are from Exhibit F-31 from the 2019 report, Tab F-31 in the spreadsheet -- values across all scenarios or basins						
Emission	Processing	Transmission Station	Storage	Transmission Pipeline	Distribution	
	Mean	Mean	Mean	Mean	Mean	
Carbon dioxide	1.33E-03	4.61E-03	4.41E-07	1.40E-07	1.02E-05	
Methane	1.38E-05	3.62E-05	1.56E-06	6.71E-06	2.86E-05	
To have a full natural gas chain value, we used Production and Gathering/Boosting value from Appalachian Shale, Table F-1 from the 2019 report, Tab F-1 in the spreadsheet						
	Production (mean)	Gathering & Boosting (mean)				
Carbon dioxide	1.36E-03	3.36E-03				
CH4	2.10E-05	4.56E-05				
To determine the distribution portion of the value chain, we used a GWP 20 of 87, consistent with the NETL analysis, to convert the methane to CO2e						
We did not include the NO2 values because they are at least two orders of magnitude lower than CH4						
	Mean values CO2	mean values CH4 x 87 (kgCO2e/MJ)	total col B + C (kg CO2e/MJ)	total col B+C g CO2e/MJ	% fraction	
Processing	0.00133	0.0012006	0.0025306	2.531	11%	
Transmission	0.00461	0.003149	0.0077594	7.759	32%	
Storage	0.000000441	0.0001357	0.0001362	0.136	1%	
Pipeline	0.000000140	0.00058377	0.0005839	0.584	2%	
Distribution	1.02E-05	0.002488200	0.0024984	2.498	10%	
Production	1.36E-03	0.001827000	0.0031870	3.187	13%	
Gathering & boosting	3.36E-03	0.003967200	0.0073272	7.327	31%	
Total:	0.005950781	0.0075577	0.0240227	24.023	100%	

Appendix B: Methodology Comparison Table

Source	GHGRP (40 CFR Part 98, Subpart W)[1]	Comparison GHGRP CO_2e (mt)	NGSI/GHGI[2]	Comparison NGSI/GHGI CO_2e (mt)	DEC Inventory[3]	Comparison NYS DEC CO_2e (mt)	Notes/Comments
Mains – Unprotected Steel	12.58 scf/hr/mi [2,115.9 kg/mi/yr]	53,320	861.32 kg CH_4/mile/yr	21,705	2,122.3 kg/mile/yr	53,482	
Mains – Protected Steel	0.35 scf/hr/mi [58.9 kg/mi/yr]	4,945	96.75 kg CH_4/mile/yr	8,127	58.8 kg/mile/yr	4,939	
Mains – Plastic	1.13 scf/hr/mi [190.1 kg/mi/yr]	31,930	28.85 kg CH_4/mi/yr	4,846	190.1 kg/mile/yr	31,937	Includes plastic liners/inserts
Mains – Cast Iron	27.25 scf/hr/mi [4,583.2 kg/mi/yr]	384,991	1,157.27 kg CH_4/mile/yr	97,211	4,597.4 kg/mile/yr	386,182	Includes copper as well as ductile and wrought iron
Services – Unprotected Steel	0.19 scf/hr/srv [31.96 kg/srv/yr] ---> 62'/srv	53,706	14.49 kg CH_4/service/yr	24,338	2,711.5 kg/mile/yr	38,824 [4]	Unclear how DEC determined service length to derive mileage-based EF
Services – Protected Steel	0.02 scf/hr/srv [3.36 kg/srv/yr] ---> 72'/srv	8,480	1.3 kg CH_4/service/yr	3,264	247.3 kg/mile/yr	5,311	
Services – Plastic	0.001 scf/hr/srv [0.17 kg/srv/yr] ---> 66'/srv	5,653	0.26 kg CH_4/service/yr	8,837	13.5 kg/mile/yr	3,866	
Services – Copper	0.03 scf/hr/srv [5.05 kg/srv/yr] ---> 54'/srv	42,400	4.9 kg CH_4/service/yr	41,146	496.0 kg/mile/yr	35,509	
M&R – Aboveground	LDC specific (see note A)		Same as GHGRP		Not included		
M&R – Belowground, > 300 psig	1.30 scf/hr/station		1.30 scf/hr/station		Not included		
M&R – Belowground, 100-300 psig	0.20 scf/hr/station		0.20 scf/hr/station		Not included		
M&R – Belowground, < 100 psig	0.10 scf/hr/station		0.10 scf/hr/station		Not included		
Combustion	See note B		Same as GHGRP		Not included		
Customer Meter – Residential, outdoor	Not included		1.49 kg CH_4/meter/yr		0.0015 mt CH_4/meter/yr [1.5 kg/meter/yr]		Unclear if DEC's meter counts are for outdoor meters only or if indoor meters are included
Customer Meter – Commercial/Industrial	Not included		9.73 kg CH_4/meter/yr		0.0097 mt CH_4/meter/yr [9.7 kg/meter/yr]		
Blowdowns	Not included		1.96 kg CH_4/mile/yr		Not included		Total miles of mains plus miles of services
Damages	Not included		30.62 kg/mile/yr		Not included		Total miles of mains plus miles of services
Pressure Relief Valves	Not included		0.96 kg CH_4/mile/yr		Not included		Total miles of mains only
End-User Combustion	0.0544 mt CO_2/Mscf [Subpart NN, see note C]		Not included		5 g CH_4/GJ (Res/Comm) 1 g CH_4/GJ (Ind) Carbon content = 14.43 MT/10^9 Btu		DEC: Tables 25 & 26, *Technical Documentation: Estimating Energy Sector …*, Dec. 2021
Imported natural gas	Not included		Not included		42,147 g CO_2-e/mmBtu [AR5, 20-yr] [~43,000 mt CO2-e/Bcf] 12,131 g CO_2/mmBtu 357 g CH_4/mmBtu 0.14 g N_2O/mmBtu		*2021 Statewide GHG Emissions Report, Summary Report* , Table A1

Footnotes:

1. See 40 CFR Part 98, Subpart W. Emission factors stem from EPA/GRI, 1996
2. NGSI emission factors are from the 2020 GHGI. For mains and services, NGSI uses emissions factors from both the GHGRP and the GHGI (GHGI EFs are shown). GHGI EFs for mains and services stem from Lamb, 2016. Lastly, NGSI only considers methane emissions and does not include EFs for CO_2 or N_2O. NGSI was developed by AGA in conjunction with EEI to allow end-users to evaluate responsibly sourced gas on a common basis.
3. DEC EFs for mains and services were back-calculated from FLIGHT data. See New York State Oil and Gas Methane Emissions Inventory: 2018-2020 Update, Table 1 (Dec. 2021).
4. An average service length of 45 feet was used to calculate CO_2e based on utility data.

Additional Notes:

A. In Subpart W, emissions factors for aboveground M&R stations are calculated by the LDC based on surveys of transmission-distribution (T-D) stations.
B. Subpart W requires reporting of combustion emissions for the following types of units: a) external combustion over 5 MMBtu/hr, b) internal combustion over 1 MMBtu/hr (or 130 hp), and c) compressor-drivers of any heat capacity. Calculation method is per Subpart C. For units combusting pipeline quality natural gas, default emission factors are: HHV = 0.001026 MMBtu/scf, CO_2 = 53.06 kg/MMBtu, CH_4 = 0.001 kg/MMBtu, and N_2O = 0.0001 kg/MMBtu. See Tables C-1 and C-2 of 40 CFR Part 98 for other types of fuel.
C. Subpart NN assumes complete combustion and therefore does not include EFs for CH_4 and N_2O. Large users ($\geq$ 460 MMscf/yr) are excluded from Subpart NN reporting.
D. CO_2e mains and services are calculated based on non-company specific estimates for comparison purposes only.
E. The emissions factors in “Comparison” columns are written as they are presented in each publication, including reference to component CH_4. Comparison columns represent the carbon dioxide equivalent in metric tonnes output if using the different methodologies.
F. The different methodologies have varying inputs that will affect the CO_2e results, i.e., for Service calculations, GHGRP and NGSI require number of services, whereas DEC requires miles of service, which would require an assumption of average service length.
G. GWP5 20 Year is used to calculate all three methodologies in this exercise as required by CLCPA. However, GHGRP typically uses AR4 100 year and GHGHI uses AR5 100 year.

Additional Notes related to EPA changes in the Gas Distribution emission factors (GHG Reporting Program vs GHG Inventory):

- Washington State University conducted a study with support from the Environmental Defense Fund and others that updated the fugitive emission factors for distribution mains and services using collected field data.
- The report was published in 2015 and is referred to as Lamb et al. (*Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States*).
- EPA has applied the factors from 2011 forward in the GHGI using Lamb et al. leak emission rates in conjunction with existing leak incidence data.
- EPA has stated that these factors represent a material improvement in the average emissions from U.S. Gas Distribution systems compared to previous studies completed in the mid-1990's. According to the U.S. EPA GHGI documentation, "Lamb et al. suggests that pipeline leaks have decreased over the past 20 years due to factors including efforts to seal cast iron joints and enhanced leak detection and repair procedures."
- To summarize, new and better data shows that the impacts of improvements made over the last twenty years have been more effective at reducing fugitive emissions than previously thought and this change captures that improved understanding.
- The Massachusetts Department of Environmental Protection has also adopted these updated factors in the GHG reporting they require.

Appendix C: Natural Gas Local Distribution Company Sample Annual Portfolio Emissions

	Con Edison		National Fuel Gas		National Grid		Orange & Rockland	
	MT CO2-e	% of Total	MT CO2-e	% of Total	MT CO2-e	% of Total	MT CO2-e	% of Total
EMISSIONS FROM IMPORTED NATURAL GAS	**8,151,992**	**30.6%**	**2,120,725**	**28.8%**	**13,302,961**	**30.2%**	**664,628**	**31.2%**
EMISSIONS FROM NATURAL GAS SYSTEM	**945,798**	**3.6%**	**316,343**	**4.3%**	**1,997,788**	**4.5%**	**43,876**	**2.1%**
Mains	144,219		130,893		429,862		14,520	
Services	70,915		54,513		346,035		6,552	
M&R Stations	638,854		2,891		16,945		333	
Residential Meters	13,341		53,987		115,747		10,133	
Commercial/Industrial Meters	54,375		32,522		138,327		7,025	
PRVs	357		792		1,749		153	
Blowdowns	1,371		2,454		6,797		311	
Dig-ins (Mishaps)	21,371		38,261		105,946		4,850	
Combustion (EPA reportable)	996		30		836,380		-	
EMISSIONS FROM END-USER COMBUSTION	**17,514,690**	**65.8%**	**4,909,550**	**66.8%**	**28,667,605**	**65.1%**	**1,416,093**	**66.6%**
Residential	5,442,837		2,628,792		12,526,881		798,531	
Commerical	6,691,341		1,285,745		5,641,295		447,620	
Industrial	96,832		929,717		1,537,707		122,814	
Electric power	5,283,160		33,255		8,937,712		47,127	
Vehicle fuel	521		32,041		24,011		-	
Other	-		-		-		-	
EMISSIONS FROM NON-GAS SYSTEM	**12,673**	**0.05%**	**7,434**	**0.1%**	**51,794**	**0.1%**	**2,996**	**0.1%**
Buildings (excluding electricty)	972		1,572		15,716		1,057	
Fleet	7,116		5,259		16,547		1,415	
Purchased Electricity	4,586		602		19,530		524	
TOTAL EMISSIONS	**26,625,154**	**100%**	**7,354,051**	**100%**	**44,020,148**	**100%**	**2,127,593**	**100%**